Exit Capacity Review for Northern Ireland Gas Transmission

Call for Evidence

Discussion Document by TPA Solutions

15 April 2016

Contents

Chapter 1: Introduction

This note has been prepared by TPA Solutions Ltd at the request of the Utility Regulator (UR). This document explores the issues associated with the potential reform of the Northern Ireland gas transmission exit arrangements. Its aim is to elicit feedback from the industry as to whether exit reform is appropriate, and if so, what arrangements might be preferred.

This document builds upon the ideas explored in the Northern Ireland (NI) – Utility Regulator (UR) Exit Regime Review Stakeholder Workshop held in the UR offices of the Utility Regulator in Belfast on 2 March 2016[1].

This document and the views expressed herein are those of the authors and have been articulated to help the industry understand the broader considerations and issues at play in the transmission exit reform deliberation. However this is only an input to the process that is written primarily from a qualitative perspective.

Stakeholders are encouraged to respond to this document to ensure that their views and quantifications can be considered prior to UR deciding on next steps including taking any decision about whether the exit regime should be reformed, and if so, how and when any reform should be implemented.

Specifically it is important that stakeholders take this opportunity to indicate any areas where the facts or interpretations in this document are considered wrong or inappropriate. Similarly, where arguments and evidence might be missing, stakeholders are encouraged to respond providing justifications and quantified evidence wherever possible.

The views expressed in this paper should not be considered as indicative, in any way, of UR's opinions. UR will make its decision based on its own assessment and other inputs, including any feedback and evidence provided in response to this paper.

Therefore the industry is requested to provide feedback about the issues raised in this document, or any others that might be pertinent to the exit reform consideration, no later than 27 May 2016 to Roisin McLaughlin at UR Roisin.McLaughlin@uregni.gov.uk.

Chapters 2 – 7 build upon the ideas and presentation material used in the 2 March Workshop and subsequent discussions with stakeholders. Chapter 2 provides overall context to potential exit reform and in particular traditional and alternative views about how capacity product and pricing issues interact in the context of the allowed revenue stream of the Transmission System Operator (TSO). Chapter 3 provides a description of the assessment framework. Chapters 4-7 explore the case made for reform, including analysis of the proposed change and an assessment in the context of the framework defined in Chapter 3 for each of short-term products, capacity booking responsibilities, capacity booking platform and ratchets respectively. Chapter 8 provides a high level summary of the major issues related to the potential reform of gas transmission exit arrangements. Chapter 9 provides an indication of the consultation and process to define a conclusion in respect of the exit review.

[1] http://www.uregni.gov.uk/publications/exit_review_workshop_presentation

Chapter 2: Context

Exit regime reform

Short-term products were introduced on 1 October 2015 for NI transmission entry capacity to ensure compliance with the EU Capacity Allocation Mechanism code (CAM)[2]. The CAM provisions are mandatory for IPs (which are a subset of transmission entry and exit points), but do not apply to "within system" exit points

During the consultation processes that preceded the introduction of short-term entry products some respondents called for the voluntary introduction of sub-annual exit capacity products to match the proposed EU mandated range of entry capacity products. UR proposed that the case for discretionary change to exit capacity should be considered for future application, while recognising that there may be distributional consequences amongst gas consumers. In its decision document[3] about the introduction of short-term products at entry, UR committed that the exit point rules would be reviewed as part of the transition to a single code. This document is part of the engagement process that delivers UR's commitment.

In deciding upon potential exit regime reform, UR will doubtless have regard to its fundamental objective which is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland which protects the interests of consumers, promotes efficient use of gas, ensures diverse, viable and sustainable long term energy supply and facilitates competition between those supplying and conveying gas.

Process

The consideration of exit reform is part of the process that will deliver single system operation including a single transmission network code for October 2017. The single code is intended to help harmonise contracts, administration and operation of gas transmission activities.

The exit arrangements component of the single code programme, and to which this document contributes, involves:

- exploring if current exit regime is fit for purpose
- assessing any suggested deficiencies
- analysing possible remedies and their potential consequences
- understanding industry perspectives and preferences
- defining the preferred exit regime
- understanding timescales for delivery (where changes are required)
- delivering licence and code changes (if and where necessary).

The specific aim of this document is to elicit final feedback from stakeholders to inform UR's decision making.

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[2] Regulation (EC) 984/2013 of 14 October 2013 Network Code on Capacity Allocation Mechanisms
[3] http://www.uregni.gov.uk/news/notice_of_consultation_on_licence_changes_for_gas_entry_products

Role of this document

This document has been written to record the assessment by TPA Solutions of relevant issues and views based upon a literature search, participation in the 2 March workshop, some further discussions with stakeholders, its extensive experience of gas access regime development (including in GB and on mainland Europe) and wider research and analysis. The document aims to represent fairly the views so far articulated by stakeholders and then to explore and assess the case for reform. It is not the purpose of this document to provide a recommendation to UR at this stage but, where appropriate, preferred approaches based upon our current knowledge are identified.

This document is designed to elicit further feedback and evidence from stakeholders so that the UR's assessment, and decision, is soundly based. Specifically it is important that stakeholders take this opportunity to indicate any areas where the facts or interpretations in this document are considered wrong or inappropriate. Similarly, where arguments and evidence might be missing, stakeholders are encouraged to respond providing justifications and quantified evidence wherever possible.

Understanding interactions

A major challenge associated with any specific regulatory reform is to understand and anticipate the likely resulting effects (both intended and unintended). Rule changes may create redistributions within one system. For example exit changes may alter the costs of service to different customers arising from product and pricing changes or different capacity booking rules. However gas regime changes may impact more widely. The current SEM arrangements may allow a generator to reflect the STC into its bid prices thereby increasing costs to electricity consumers by inflating electricity wholesale prices (SMP) when gas plant using STC sets the SMP or constrained-on payments when gas plant using STC is called. Therefore, gas exit pricing might influence electricity wholesale market functioning which could in turn affect electricity consumers' final electricity charges in NI and the RoI.

Thus regulatory decisions are becoming ever more complex given these interactions. No longer can decisions be taken in isolation. What appears sensible from one perspective may have unintended, and perhaps undesirable, consequences when assessed from an alternative perspective.

The regulatory challenge is therefore to assess potential changes from both an intra and inter-regime perspective. The overall objective is to deliver changes which may need to reflect preferred outcomes (from an intra-regime perspective) whilst at the same time minimising distortions elsewhere (from an inter-regime perspective). A consideration of trade-offs may be necessary.

Rules in one regime (e.g. SEM) might seem to encourage change in another (e.g. NI gas exit arrangements). However the regulatory process must allow an opportunity to assess firstly whether there is a case for considering reform, and then, if reform is necessary, in which regime the reform should take place.

The aspiration for joined-up, coherent decision making across regimes and jurisdictions is obvious although deciding what, and where, changes need to be made will be more challenging.

Gas product, pricing and allowed revenue interactions

Before exploring an analysis of the case for exit regime reform and some of the detailed design issues it may be helpful to explore some of the fundamentals associated with product, pricing and allowed revenue and their interactions. This is critical given the often different aspirations of market players when exploring the merits, or otherwise, of different design choices.

This section focuses on the gas regime, specifically costs and revenues associated with transmission service, and does not consider the secondary impacts into other regimes (e.g. effect on electricity market functioning).

Transmission services revenues are largely fixed[4] and associated with long-lived network assets. Gas transmission is a capital intensive industry; substantial capital investments require sufficient revenue streams over the lifetime of the asset to enable adequate returns on investment and recovery of capital. Thus in regulated networks, assurances about allowed revenue streams are provided to take account of the recovery of capital costs (return and depreciation) and operating costs. Typically these regulatory settlements define the underlying annual revenue entitlement that compensates the service provider for those essentially fixed costs arising within that timescale. The processes, merits and challenges of this approach are outside of the scope of this paper, but establishing a reliable annual revenue stream with a commensurately low cost of capital is generally considered to be in the public interest.

The challenge then becomes how to recover the determined annual revenue requirement.

Typically a mix of capacity and commodity charges are used. Capacity bookings in an entry/exit regime grant the purchaser an option to input or offtake gas to or from the system. Capacity charges are paid for capacity levels booked before gas flows; this defines an option to flow gas up to the booked level. Commodity charges are levied on actual energy flows. Network users therefore pay both reservation charges for capacity booked (regardless of whether it is used) plus usage charges.

It is a policy matter whether and to what relative extent both capacity and commodity charging are used. The traditional wisdom has been that capacity should be predominantly used given the largely fixed underlying cost base, with commodity based charging being optional and typically applied for a minority of the allowed revenue stream.

Pricing and capacity product definition are inseparable. The aggregate of all revenues, derived from capacity revenues (reflecting capacity product prices and associated booking levels) and commodity revenues (reflecting gas flows and associated commodity prices) are designed to deliver the allowed revenue.

[4] costs related to the physical flow of gas are generally small

Whilst the anticipated European Tariff code[5] indicates that allowed revenue shall be recovered by capacity-based transmission tariffs it does allow commodity charging to co-exist with capacity charging. The current drafting does not seem to constrain significantly the split of revenues between capacity and commodity.

However the product/pricing choices will create different transmission costs across different usage classes.

The traditional approach to capacity definition and pricing has been based on a contribution to peak cost delivered using a single capacity product of one year duration. No approach can be considered perfect and so alternative approaches have been adopted.

This section first describes the traditional approach and then explores an alternative approach based on the availability of sub-annual capacity products[6].

- **Traditional annual based capacity regime**

The concept is that relevant actors should pay for capacity options proportional to their anticipated peak usage. Thus they should book a level of capacity that is consistent with their highest possible flow requirement.

The TSO only offers an annual capacity product.

The revenue to be obtained from the annual capacity is divided by the anticipated aggregate of the bookings to derive the unit price of the capacity[7]. This price is usually expressed in terms of money per energy quantity/day. For example the current (2015/16) NI Annual Exit Capacity price is £0.27044 per kWh/day. This means that an annual strip of one MWh capacity per day would cost £270.44.

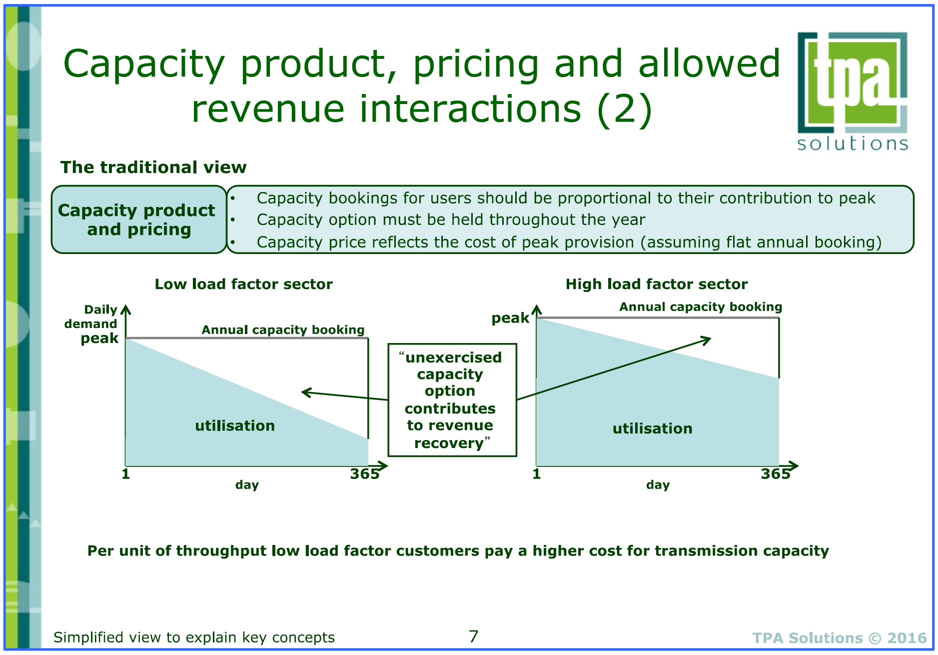
Annual capacity bookings confer total flexibility of use up to the capacity booking level although the capacity holder has to pay for this right regardless of whether the option to flow gas is exercised.

The effect is that ***per unit of throughput***, customers with a low load factor (such as residential heating) pay a higher cost for transmission capacity than those with a higher load factor (such as industrial process). This is illustrated in the diagram below.

[5] Most recently available draft is dated 26 February and was discussed at the Member States informal pre-comitology meeting on 10/11 March 2016

[6] This is the standardised capacity product approach as reflected in European rules for IP capacity

[7] For example if the revenue recovery is £20m and the aggregated bookings are expected to be 80 GWh/day then an annual strip of capacity would cost £250 for 1 MWh/day (daily equivalent 68 p per MWh/day)



Payments for annual capacity confer an option to flow gas throughout the year with payments typically made on a one-twelfth basis throughout the year to deliver a stable monthly cash flow to the TSO.

The traditional approach is designed to achieve an equitable revenue recovery across the users based on their contribution to the anticipated peak demand. Given that costs are largely fixed and primarily related to the sunk costs of investment in network it has generally been considered to be a fair means of revenue recovery. Proponents of this approach advocate that the underlying cost driver is the provision of assets to support the peak day demand and that therefore basing capacity revenue recovery on annual products reflecting peak day requirements of individual users delivers a robust cost reflectivity.

The approach has obvious merit where individual users are expected to have a coincident peak requirement on the system. Users requiring off-peak capacity, to the extent such capacity is booked by others and is (partly) unused, can use a secondary market[8] as an alternative to booking all their needs as annual capacity directly from the TSO ("primary" capacity).

However a primary annual capacity product is not the only option and other gas capacity regimes have recognised that there might be some merit in introducing a more flexible regime that offers sub-annual products directly from the TSO.

Proponents of an alternative approach associated with the availability of short-term (i.e. sub-annual) products suggest that the annual product is not entirely satisfactory in so far as it may have some detrimental effects on some market players (particularly those wanting to make infrequent use of the system). Additionally, given wider interactions with other regimes (e.g.

[8] A mechanism whereby capacity holders can trade entitlement with one another.

electricity market) some actors may have a strong commercial incentive to seek gas transmission exit short-term capacity products (STCs).

Advocates of the traditional approach would counter that the TSO should keep the primary capacity product (and pricing) simple (i.e. annual) whilst allowing secondary markets to emerge as the best way to procure (and price) any greater flexibility for those that need this.

- **An alternative perspective**

The existence of short-term products[9] would allow users greater flexibility of primary capacity booking by allowing an opportunity to optimise bookings taking account of anticipated gas flows and the relative pricing of different capacity products.

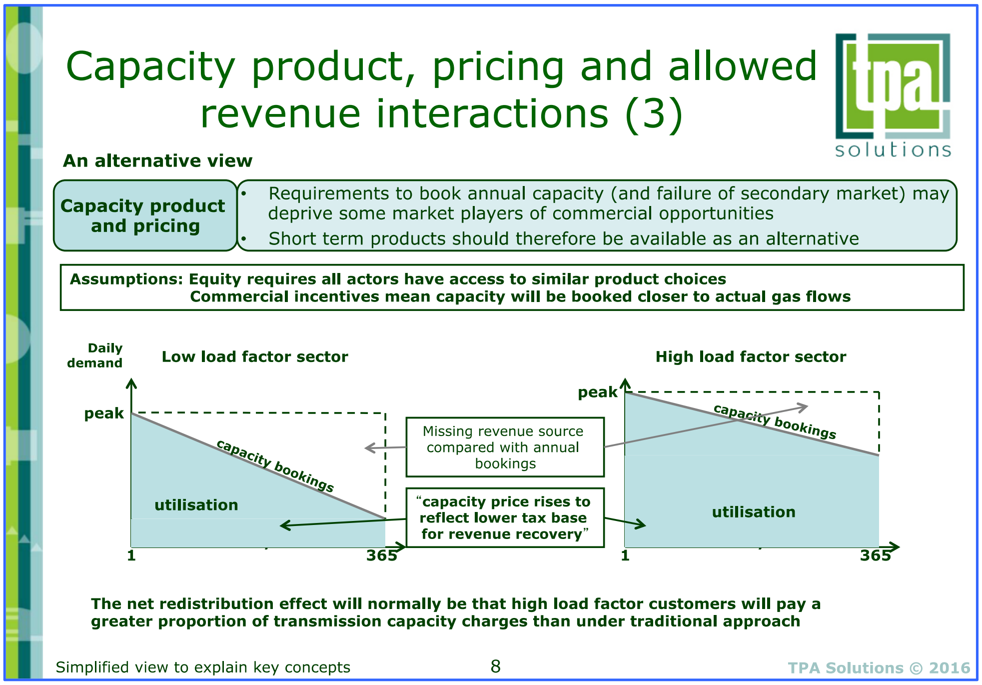
Where capacity booking levels are not mandated, individual capacity bookers would be able to financially optimise their bookings taking account of both relativity of STC pricing[10] (i.e. to minimise actual gas transmission charges) and potential interactions with other regimes (because the cost classification within SEM may be different for annual and sub-annual products.

The availability of STCs should therefore be expected to lead to a decrease in capacity bookings. A particular challenge of STCs is deciding how the sub-annual products are to be priced. The authors are not aware of any published analysis that supports the recent setting of relative STCs[11] prices despite their widespread prevalence in European gas regimes.

Where capacity is considered to be adequate to satisfy demands capacity users will optimise their bookings wherever they are so enabled. This is likely to involve deferring at least some capacity purchases until closer to gas flow. Overall bookings should be expected to decrease; and the prospect of reduced bookings[12] implies that the headline price for a unit of capacity may have to go up to compensate.

The net effect will be a redistribution, across customer classes, compared to the “annual capacity only” regime. High load factor customers will typically pay a higher proportion of transmission capacity charges than under the traditional, “annual capacity only” approach. Low load factor customers will face lower overall charges. Effectively the approach moves closer to a commoditisation of revenue recovery which is rather different to that associated with the burden being apportioned proportional to contribution to peak requirement. (See diagram below.)

[9] This note does not prescribe the durations of STCs. However the gas regime is tending towards standardized products based on quarters, months and days as currently implemented with the NI gas transmission entry regime.
[10] Short-term product pricing might well be determined by the application of multipliers (which define the price ratios of a day’s capacity in short-term products to the annual product) and seasonal factors (additional multiplicative factors applied to derive different price relativities between capacity booked for different parts of the year).
[11] Whilst the current Tariff code envisages some constraints are to be defined to STCs price setting this only relates to IPs. NI may need to amend entry multipliers and seasonal factors should the current Tariff proposals prevail. The Tariff code provisions are unlikely to apply at exit although some justification for the resultant pricings for sub-annual products, if introduced, may be necessary given the scope for redistribution of charges between different users.
[12] Compared with those anticipated in an annual capacity only regime



The above provides an essential foundation for some of the assessments made later in this paper. It should be noted that the redistribution effect described above may not apply where there is not the exercise of free choice for all users. For example, any low load factor customers who are unwilling or unable to access shorter term capacity products will typically experience an increase in capacity charges, assuming that the underlying unit price for capacity has indeed been increased.

Chapter 3: Assessment Framework

The assessment of any proposals for change to the gas exit regime will need to be made in the context of UR's statutory objectives in relation to gas which are to:

- promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland
- protect the interests of gas consumers
- promote efficient use of gas
- ensure diverse, viable and sustainable long term energy supply, and
- facilitate competition between those supplying and conveying gas.

In order to frame these considerations, it is helpful to appreciate the broader context in which exit regime reform is to be considered as well as understanding the specific criteria against which any decision will be made.

The broader context includes the provisions that:

- TSO allowed revenue recovery is assured
- revenue recovery is delivered in a timely manner and consistent with the mutualised approach that delivers low overall costs to NI gas consumers, and
- assessments are made in the interests of consumers.

The third provision is generally considered synonymous with low cost of service, effective retail and wholesale competition and security of supply. The consideration needs to cover NI gas and electricity consumers as well as wider cross-border considerations including the operation of the Single Electricity Market (SEM) which may extend the deliberation to both gas and electricity consumers in both NI and RoI.

In summary the assessment needs to involve joined-up thinking across gas and electricity and across NI and RoI.

Another important issue is proportionality.

The NI gas market is relatively small. For example NI has around 200 thousand gas consumers compared to more than 20 million in Great Britain (GB). Demand levels differ; 12 TWh per annum in NI compared with more than 700 TWh in GB. Effectively 4 transmission exit points in NI compared with more than 200 in GB. Administrative, contractual and IT costs associated with NI reform include a substantial fixed element not directly related to customer numbers or demand levels. These costs have to be borne by a relatively small customer base. So very clear benefits are needed to justify these higher unit implementation costs, implying a need for more rigorous assessment to support the case for reform than might be the case in larger markets.

Besides these general considerations, regime reforms are often additionally assessed against a range of criteria. This paper considers three: cost reflectivity, efficient network use and effective development, and effective competition. Given the subjective nature of such terms an initial interpretation is offered:

- **cost reflectivity**

Revenue apportionment should relate to underlying cost generation. Network users should pay for services which closely matches their usage of assets, network and wider resources

- **efficient network use and effective development**

Products, pricing and associated rules should

  - encourage use of the system where marginal benefit exceeds marginal cost. Thus incremental use of the system should develop a contribution to revenues to the benefit of all other users
  - enable network expansion to meet economic demand without any excessive investment ("gold plating")

- **effective competition**

Products, pricing and associated rules should promote retail and wholesale competition (for both gas and electricity).

Later chapters of this paper consider short-term products, capacity booking responsibilities, capacity booking platform and ratchets. Each chapter considers each on an individual basis.

Stakeholders are invited to respond to the following questions:

- **Is the basis for assessment appropriate?**
- **Are the broader assessment framework and the specific criteria clearly articulated?**
- **If not how should the assessment framework be evolved?**
- **Are there any other criteria which should be considered?**

Chapter 4: Short-term Products

Proposal under consideration

To introduce short-term products to enhance market functioning.

Case for reform

The electricity market is evolving. Renewable generation continues to grow, thereby increasing the likely intermittency of use of gas fired generation plant. Gas fired generators indicate that recovery of their fixed costs is becoming more challenging and that the current annual capacity regime may contribute significantly to this issue.

Discussion and research of related papers/correspondence identified four arguments in support of the introduction of short term capacity ("STC") products to the NI gas transmission exit regime that were presented at the 2 March Workshop, namely:

- Allows matching of booking with utilisation
- Allows level playing field with RoI generators
- Better enables new NI generation
- Consistency with entry capacity arrangements.

Following discussion with stakeholders we consider that an additional, fifth consideration is the classification of gas capacity costs in the functioning of the electricity market (SEM).

Analysis

This section analyses the four arguments in favour of the introduction of STC and our additional consideration.

- **Allows matching of booking with utilisation**

Proponents advocate that users should only pay when the user is using the system, and then only to the extent of actual gas flows. The requirement for infrequent users such as an electricity generator to book an annual capacity product creates an unacceptable cost burden that may not be recoverable for the generator. This "annual capacity only" exit regime therefore contributes to the gas generator's inability to recover all of its fixed costs. The cost burden might be so great that it could force a power station to exit the generation market, or to switch to an alternative fuel. Should this happen the gas transmission network costs would be borne by a smaller user base.

However, network costs are mainly driven by the cost of peak provision and therefore the cost reflective objective implies that those contributing to peak demand should pay in proportion to their expected peak demand. This is consistent with the capacity concept that an option is being purchased to satisfy their requirements when the system is being used to its maximum.

Allowing matching of booking with utilisation would reduce the amount of capacity booked and increase the headline price for capacity, given that allowed revenues will still need to be recovered. Short-term capacity products will therefore create redistributions within the regime when compared with an "annual capacity only" regime.

- **Allows level playing field with the RoI generators**

Proponents of STC observe that such products are already available in the RoI regime. NI generators are therefore at a disadvantage compared with those in the RoI and that STC introduction in NI would remove this inequity.

Our recent stakeholder meetings have highlighted the criticality of SEM interactions which are explored in more detail under the fifth consideration.

Introducing STC in NI gas transmission exit would imply consistency with the RoI product definition. The merits of consistency may, however, be over stated. Product and pricing regimes should be considered in the context of local gas regime and interactions via electricity arrangements. The precise benefits of product alignment have been asserted but have not been justified. Even if similar product structures are available a level playing field will only be delivered in the RoI and NI if gas capacity prices are the same.

- **Better enables new NI generation**

Proponents advocate that STC will enhance the prospects of new NI generation. Under SEM NI generators will be able to recover STC costs when they are constrained-on i.e required to generate outside of the merit order for locational reasons to maintain system integrity.

However SEM will be evolved to I-SEM from October 2017 when new capacity remuneration mechanism and electricity trading arrangements will be introduced. This initiative is designed to facilitate an adequate and diverse generation mix that can accommodate the economics of different plant types. The location of new generating plant will be determined by many different factors.

- **Consistency with entry capacity arrangements**

Proponents of STC argue that NI already has STC at entry and therefore should be made available at exit given that incremental costs of implementation would be small.

The entry arrangements were introduced to deliver compliance with EU regulations given that the two NI entry points are IPs rather than because there was any obvious and explicit merit from a local perspective.

The EU rules are not mandated at national exit points so the NI exit regime is for local determination.

The EU approach was designed to best enable efficient gas flows where multiple sourcing options exist. The underlying idea at entry is that competition and diversity in the sourcing of gas flows should be encouraged and facilitated. At transmission exit points the flows are determined by the needs of final customers, a very small number of direct connects and the DSOs, where there is no competition in respect of the destination of flows. In essence, at entry points there is benefit in accommodating a greater diversity and flexibility of gas sourcing options. This diversity does not exist at exit.

Thus the two drivers for STC at IPs, the mandatory requirement and the perspective of competitive benefit, do not apply in respect of NI gas transmission exit capacity.

- **Classification of gas capacity costs in the electricity regime**

Our discussions with stakeholders have indicated an important underlying driver for promoting the introduction of STC within NI exit reform; the classification of gas capacity costs in the electricity regime (SEM). SEM rules create pressure for a change in the gas regime.

Proponents advocate that generation profitability is inadequate and needs to increase so that revenues at least cover underlying costs of operation. The interaction with SEM offers an opportunity to increase revenues specifically because SEM requires a classification of costs into short-term and fixed costs.

The current SEM arrangements may allow a generator to reflect the STC into its bid prices thereby increasing costs to electricity consumers by inflating

- electricity wholesale prices (SMP) when gas plant using STC sets the SMP; or
- constrained-on payments when gas plant using STC is called.

These impacts occur because annual capacity payments are treated within SEM as fixed costs of generators doing business, whilst STC costs are allowed as marginal costs of generation. For example, NI gas exit STC prices would become recoverable for NI generators in constrained-on situations.

Generators argue that short-term products should be introduced in the gas exit regime to avoid an inappropriate cost burden in respect of gas exit charges and to have products that better enable them to maximise revenues in SEM. The generators also argue this has benefits for the generality of gas users; if the opportunity is lost and gas fired generation is consequently retired then the transmission bills for other gas consumers will rise.

Proponents indicate that relative prices of annual and sub-annual products could be set so that other gas customers may not necessarily experience any increase in gas costs as a result of introducing STC. This confirms that the multipliers and seasonal factors, that determine the relativities of annual and sub-annual products, are of secondary importance to the existence of STC from the proponents' perspective. It would appear that generators are not worried about their total gas capacity costs, provided they can be included in SEM bids.

Proponents argue that STC exists at both transmission entry and exit in the RoI and has recently been introduced in NI at entry and therefore extension to NI exit would be easy and beneficial.

Assessment

This section provides a qualitative assessment of the merits of introduction of STC based around 3 questions:

- is it appropriate to solve an electricity problem with a gas regime change?

- is there a material risk of losing generators as gas customers in NI?
- is the introduction of STC a no regrets initiative?

It then makes an assessment against the three specific criteria defined in Chapter 3:

- cost reflectivity
- efficient network use and effective development
- effective competition.

- **Is it appropriate to solve an electricity problem with a gas regime change?**

Our discussions with stakeholders have indicated a concern that generators might not be able to cover their fixed and variable costs of generation. Gas exit capacity costs are only a part of a generator's cost base and so the issue is much wider than just NI gas exit capacity treatment. Adequate profitability of generators is essential to deliver security of electricity supply. The electricity framework should enable sufficient revenue streams for efficient generators.

The SEM is to be evolved, to meet new challenges, by October 2017. The reformed market, I-SEM, will make changes in the manner in which generation capacity payments, wholesale electricity prices and constrained-on costs are determined and treated.

Introducing gas exit STC would seem to increase electricity prices; it might be better to consider whether this part of the SEM design is appropriate as is currently being done within the I-SEM development rather than make changes in the gas regime to respond to features of the current SEM thereby minimizing the regulatory risks associated with making changes in both the electricity and gas regimes.

The critical issue here seems to be the adequacy of payments made to generators to cover their fixed costs of participation in the SEM. We believe this should be addressed via the electricity framework. Since it is unlikely that generators' issues about wider cost recovery could effectively be dealt with by gas transmission exit reform it seems prudent to at least wait the outcome of SEM reform before considering the introduction of gas exit STCs.

We note that in November 2015 the SEM committee published a consultation on market power mitigation in the I-SEM. The I-SEM conclusions document, which we understand is expected in May, might provide greater clarity about how the new electricity arrangements may influence electricity wholesale market price formation including the treatment of different underlying costs and how they affect bid prices. This should provide further context for responses to this call for evidence.

- **Is there a material risk of losing generators as gas customers in NI?**

If generators are not financially viable then they will cease their gas offtake. This would detrimentally affect the generality of gas customers because no contribution towards the allowed revenue would be received from those lost customers.

The recent EU mandated entry reform may have somewhat helped the economics for NI generators by introducing short-term products. Furthermore commodity charges can be considered short-term. Therefore only the gas exit capacity component can be considered inadmissible as short-term cost in SEM. It is unclear under what circumstances the availability of only an annual gas exit capacity product would be decisive factor in a decision not to offtake gas, or to mothball, or close a plant.

The materiality of the risk of loss of generation load should therefore be established before any exit reform should be contemplated given the costs and risks of making a reform. Furthermore the benefit, arising from reform, necessary to reduce the risk of lost load to an acceptable level would need to be quantified.

Quantified evidence to define such scenarios would be welcomed in responses to this consultation.

If this risk is high then there could be merit in adapting the access regime and pricing[13] to enable such consumers to continue in business and thereby make some (albeit reduced) contribution to the allowed revenue.

We explain below that introducing STC is not a simple, no regrets option. A careful formulation of the detailed implementation would be necessary to assess the impacts. The full ramifications of the introduction of STC may take several years to discern depending upon how quickly changed booking behaviours occur. For example we note that it is several years since GB reformed its exit short term products and booking behaviours are still evolving and generating challenges for both price setting and timely revenue recovery.

Should STC be introduced then it will increase electricity prices. This feels inappropriate although we understand that proponents believe that the effects in the combined RoI/NI electricity market will be very small when expressed in a p/kWh total energy consumed basis.

- **Is the introduction of STC a no regrets initiative?**

One generator has suggested that short-term products should be introduced as a matter of urgency. However the gas exit review has indicated the complexity of the interaction between regimes and the potential risks of unintended consequences. It is not clear that exit regime reform is a no regrets option; the ramifications go well beyond minor distributional effects between gas shippers and indeed may have significant impacts on the costs faced by electricity consumers. For the reasons that follow we caution that a thorough design of detailed STC implementation is needed before any decision should be considered. If gas regime rather than electricity reform is needed then, as indicated above, we believe that other approaches should be assessed, and might be considered preferable, to STC.

The introduction of STC would complicate tariff and booking processes. If STC was introduced it would seem to be necessary, from an equity perspective, to make short-term products available at transmission offtakes into the DSO as well as at direct connects (i.e. power stations). To do otherwise would seem to discriminate in favour of directly connected customers at the expense

[13] Any price level above the short term marginal cost would generate a contribution to the benefit of other players.

of downstream consumers offtaking from the distribution zones. This issue is explored more comprehensively in the Capacity Booking Responsibilities Chapter 5.

The uncertainty of transmission income cash flows is likely to be greater because of:

- the increased uncertainty of capacity bookings
- the requirement to set relative prices for standardised products of different durations
- seasonal pricing

leading to risks of larger bullet payments/receipts under the year-end process to reconcile allowed revenues.

The complexity of capacity price determination, booking arrangements, changes to Licence and Network Code, and the administration of implementation will inevitably create additional costs that will need to be absorbed by a relatively small customer base. Therefore a high degree of confidence about the benefits of change, which may only accrue to a subset of users, is required to support a regime reform recommendation. Thus from a proportionality perspective it is not clear that the case for short-term products would be justified.

Introducing short-term capacity would require a more sophisticated methodology to seek to attribute costs to the various products. Our assessment is that parameters may be difficult to justify and therefore may be subjective. Unless distorted by external factors short-term capacity should be expected to move capacity booking closer to utilisation. Where price setting comprises a unit multiplier for short-duration capacity and no seasonal factor adjustment and the network is not subject to constraints, the sub-annual products would likely deliver the same effect as a fully commoditised regime. This is far away from the original objective of capacity regimes.

For some this may reduce costs; for others it may introduce opportunities for the costs of short-term capacity products to be passed through via the rules of another regime as, for example, is the case with SEM.

It has been suggested that the gas exit STC prices could be set so that a similar revenue recovery is obtained from power stations as in the “annual capacity only” situation. Given current SEM functioning this could deliver the favourable outcome sought for the generators but at the cost of electricity consumers in the single market. Whilst it has been suggested that these effects would be small, when distributed against the whole of the RoI and NI electricity customer base, such an outcome seems perverse. If there is a problem associated with efficient fixed cost recovery for generators then this would be better addressed via transparent I-SEM reforms rather than resolved via network charging in the gas exit regime.

In any case, it is somewhat troubling to the authors that the ultimate thrust of the argument in favour of change appear to be that gas consumers need not be too concerned about the uncertain distributional effects of STC because it is unlikely that non-generation users will have to pay more – it’s just the price of electricity that will go up!

To conclude this chapter an initial assessment against the specific criteria identified in the Assessment Framework chapter follows. This assessment compares a regime based upon short-term product availability with the current “annual capacity only” situation.

- **cost reflectivity**

Given the aspiration that capacity reflects an option to flow gas the “annual capacity only” regime would seem to provide a more appropriate allocation of the costs of the option to individual network users.

The setting of multipliers and seasonal factors in a short-term products regime will necessarily involve subjective judgements. These need to reflect a number of objectives including: delivery of opportunities in the market (an objective would be to tilt the playing field compared with annual only regime) and seeking to deliver the allowed revenue requirement. Achieving the allowed revenue via sale of capacity (rather than via ex-post reconciliation) will require the price setting process to anticipate network users’ individual responses to the differential prices between annual and sub-annual capacity products. It is not clear to the authors how cost reflectivity of products on a sub-annual basis can be delivered given these other market and allowed revenue constraints. Indeed it is likely that there will be trade-offs between competing objectives.

This suggests that the introduction of short-term products can only be detrimental to the cost reflective criterion.

A case for change would therefore need positive arguments in other criteria that more than outweigh the negative associated with the assessment against this criteria.

- **efficient network use and effective development**

The network has been built to satisfy at least the requirements of all currently connected loads. The efficiency of network use might be increased if new additional off-peak load was to connect to the system without imposing additional capital cost requirements and where it would then make a contribution to overall costs. This would deliver a benefit to other users. However, we are not aware that any such potential loads have so far been identified.

The introduction of short-term products might be considered likely to diminish the ability to obtain forward looking planning and investment signals associated with new loads. Superficially this may appear detrimental although we understand that in reality the transmission system is designed using a market planning and forecasting process that is based upon DSO 1 in 20 obligations and potentially via longer term commitments for very large direct connect loads.

Therefore the introduction of short-term products is considered broadly neutral in respect of this criterion.

- **effective competition**

Short-term exit capacity product availability may provide additional opportunities for existing and new demands for gas compared with the annual product. It should be noted that STC confers no benefit over annual in terms of operational flexibility per se, but might be justified by the ability for some users to reduce their own cost of access to the gas system. It can be argued that STC in NI would allow NI generators to compete more effectively with those in the RoI.

The introduction of short-term products would risk some unintended detriment to market functioning, including increased uncertainty about achieving how allowed revenue is secured. Short-term products will likely increase the scale of reconciliation adjustments rendering gas retail players less able to forecast the cost of their services to gas consumers and therefore potentially decreasing the efficiency of the gas retail market. Additionally, some of those advocating most strongly for the early introduction of short-term capacity clearly expect it to contribute to increased prices for electricity consumers.

Overall the assessment against effective competition is considered somewhat mixed, with negative consequences perhaps outweighing any positive intent.

The analysis presented in this paper therefore points towards an initial recommendation that short-term products should not currently be recommended for the NI gas transmission exit regime.

The generators' claimed inability to adequately recover their fixed costs needs to be established before any gas exit reform is contemplated. Given that the fixed costs are far wider than gas transmission exit costs it seems inappropriate, at present, to attempt a quick-fix via gas regime rules that could only address part of the issue, especially since STC is evidently not a simple "no regrets" decision. It appears to the authors that the fundamental issue arises in the electricity regime and should be resolved in that arena. The I-SEM design should be completed so that market rules and associated capacity remuneration mechanisms are defined to satisfy both market and security of supply aspirations. Coherent gas and electricity regimes then need to be implemented via co-ordinated efforts by all market actors and relevant regulators.

Stakeholders are invited to respond to the following questions:

- **Are the 4 key arguments and the 5th consideration captured appropriately?**
- **Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?**
- **Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.**
- **Are the assessments of the case for short-term products appropriate with regard to the specific criteria? If not please explain in your response.**

Chapter 5: Capacity Booking Responsibilities

Proposal

Change booking responsibility so that shippers directly book transmission exit capacity.

Case for reform

The current arrangement is that the Distribution System Operator (DSO) books an annual exit capacity product on behalf of its downstream network users. The DSO's booking reflects the expected 1 in 20 demand in compliance with its Licence requirements. Power generators directly connected to the transmission network book their own exit capacity. There is no obligation on power generators to make bookings at any specific demand level, although there may exist take or pay capacity and flow contracts designed to cover historical network investment costs.[14] Note that ratchets are currently applied if the booking level is below any day's actual offtake at any point during the year. Ratchet application is considered in Chapter 7. A potential alternative could be to allow downstream network users to signal their individual requirements i.e. be afforded the same risks/responsibilities as power generators. Stakeholders present at the 2 March workshop did not comment on the need for a change in capacity booking responsibilities.

Analysis

Capacity booking responsibilities can be broken down into two distinct issues; specifically who books and what level is booked.

- **Who books?**

The DSOs already have an established process for booking transmission exit capacity and pass on the associated capacity costs to shippers. As there is full cost pass through of transmission exit capacity charges and a change would require new processes there would seem little advantage to the DSO of change.

Any change would introduce complexity for shippers and create additional interface requirements with the TSO.

- **What level is booked?**

It is assumed that the current requirement on DSOs to book at the 1 in 20 peak level would be transposed onto shippers. Thus an individual shipper's bookings would be those associated with its contributions to the DSO peak.

[14] There is currently such a contract in place for one of the two NI power stations.

Note that the transfer of responsibilities can be considered independently of any change from an annual booking regime to one which incorporates short-term bookings.

Assessment

As with the assessment of short-term products earlier, the same general considerations of equity, complexity and proportionality have to be considered if any changes are to be made. Therefore the initial view is that there would be increased complexity with no obvious benefit. Further consideration will be given in the ratchets chapter in regard to what level is booked.

An initial assessment against the specific criteria identified in the Assessment Framework chapter follows. This assessment compares a regime with network users taking responsibility for the booking process with the current DSO booking situation.

- **Cost reflectivity**

Allowing network users to signal individual requirements is unlikely to improve cost reflectivity because the DSO uses an established process, involving consultation, for determining the 1 in 20 demand level in accordance with the Licence. It is considered unlikely that a range of shippers operating in a competitive market would, by each making forecasts and then booking accordingly deliver a better outcome. Commercial drivers would imply a tendency to under-book compared with the current 1 in 20 booking obligation. The alternative is that the network user would have to mirror the DSO's process and the end result would be the same. Total costs would increase for end consumers due to the added complexity for both DSOs and their network users. The initial assessment against this criteria is therefore negative.

- **Efficient network use and effective development**

The TSO forecasts future exit requirements in consultation with its users as part of its network planning process. TSOs, DSOs and market participants have considerable experience built up over many years in the use of transparent statistically based forecasting approaches to assess the 1 in 20 requirements for downstream connected loads. More importantly, the long term booking process is not expected to change so there would be no effect from changing the responsibilities. The initial assessment against this criteria is therefore neutral.

- **Effective competition**

DSO capacity is currently booked consistent with a 1 in 20 aggregated demand. If this requirement is transposed to network users then aggregate bookings will not change. Requiring network users to book transmission exit capacity will add complexity and cost to their business which ultimately will be borne by end consumers. It is simpler to manage through the DSOs and since no tangible benefits have been identified, the initial assessment against this criteria is therefore negative.

TPA's initial assessment is that the case for changing the capacity booking responsibilities for DNO users is weak and should not be considered further.

Stakeholders are invited to respond to the following questions:

- **Are the arguments above captured appropriately?**
- **Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?**
- **Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.**
- **Are the assessments of the case for a change in booking responsibilities appropriate with regard to the specific criteria? If not please explain in your response.**

Chapter 6: Capacity Booking Platforms

Proposal

PRISMA to be used as the only capacity platform for entry/exit capacity booking.

Case for reform

The existing PRISMA platform could be used to deliver gas exit STCs. PRISMA, however, only address a small part of the overall capacity process namely accepting network users' bids into the auctions and the allocation process. All other parts of the process will still need systems and procedures that will impact both the TSOs and the network users. Whilst PRISMA could provide a partial solution to the implementation this chapter provides an analysis of the risks associated with using that approach and captures further implementation issues that will impact TSOs and network users.

There is currently a simple booking system for exit capacity which involves the two DSOs and shippers to the power generators booking with the TSO. Stakeholders have suggested that the European booking system PRISMA, recently adopted for entry at IPs could also be used for exit. If short-term capacity were to be introduced and assuming that it would be appropriate for the exit regime to follow the PRISMA standard format as adopted for entry then there may be some potential for savings in system development costs. However, it is important to remember that PRISMA only delivers the basic front end system (namely accepting network users' bids into the auctions and the allocation process) and TSO systems would still be required for the much more significant processing post initial sale. Using PRISMA would require an interface between all the relevant parties and PRISMA. A new interface would be required should the DSO hold the relevant responsibility. Stakeholders present at the 2 March workshop did not comment on the choice of capacity booking platform.

Analysis

A single system across PTL, BGTL and GNI(UK) covering both entry and exit capacity bookings would be preferable from a user perspective. However, as with any system development the initial costs and potential costs for future change or deviation from the PRISMA standard would need to be carefully considered. Controlling costs within the PRISMA system is likely to be difficult and a dedicated NI exit booking system is expected to be more cost effective.

Assessment

The general considerations of equity, complexity and proportionality have to be considered in the choice of an exit booking platform. It is not obvious that there will be significant cost savings in using PRISMA for exit bookings and this needs to be considered in relation to the potential lack of flexibility in product design and capacity pricing provided within PRISMA. Given the lack of stakeholder requests for change in who books capacity and the initial view that there would be increased complexity with no obvious benefit there would appear to be no case to be restricted to PRISMA rather than a more flexible local system in relation to these general considerations. The PRISMA system (and its costs) may not be proportional to the relative size of the NI market.

An initial assessment against the specific criteria identified in the Assessment Framework chapter follows. The assessment compares a regime with PRISMA rather than a local NI system for the booking of exit capacity.

- **Cost reflectivity**

The choice of capacity platform does not influence cost reflectivity (but may increase administrative costs). The initial assessment against this criteria is therefore neutral.

- **Efficient network use and effective development**

The choice of capacity platform does not influence network development. The initial assessment against this criteria is therefore neutral.

- **Effective competition**

This is best served by an efficient simple and flexible local NI system which would not constrain exit products or their pricing to that of the PRISMA standard since there is no requirement for such consistency at non IPs. This assumes that costs of a local system, or changes thereof, will be cheaper than via PRISMA. The initial assessment against this criteria is therefore negative.

TPA's initial assessment is that the complexity and potential inflexibility of PRISMA may not be best suited to the relative size of the NI regime. More specifically at this stage, TPA considers that the choice of capacity booking platform should be subservient to decisions over STC adoption and capacity booking responsibilities.

Stakeholders are invited to respond to the following questions:

- **Are the arguments above captured appropriately?**
- **Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?**
- **Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.**
- **Are the assessments of the case for using PRISMA for the booking of exit capacity appropriate with regard to the specific criteria? If not please explain in your response.**

Chapter 7: Ratchets

Proposal

Deliver incentives to book appropriate levels of capacity in advance of gas flows.

Case for reform

A ratchet mechanism is an arrangement whereby shippers who exceed their booked annual level are charged retrospectively for the shortfall. There is currently a straightforward ratchet in operation in place at exit in NI whereby a transmission system user may book (and pay for) capacity at a level below their annual peak day and when this level is breached simply pays for the shortfall at the annual rate[15]. There is hence no commercial incentive to book maximum (peak) exit capacity (or even lower levels) as the capacity rate per unit ratcheted is the same as if the capacity had been booked from the beginning of the year (ie the ratchet factor[16] is 1).

Thus, other than in the context of the DSO's 1 in 20 booking obligation,[17] the regime incentivises under-booking since there is then no risk of paying for capacity that is not required. In addition, there is a cash flow benefit (for those that under-book relative to those that do not). In essence, the current regime does not incentivise bookings consistent with capacity levels to which the network has been designed. As discussed in chapter 4, accurate booking levels facilitate transmission capacity charge setting and reduce reconciliation payments for all users.

Therefore the following options could be considered:

- a ratchet mechanism that enhances the incentive to book exit capacity accurately; and/or
- an appropriately priced over-run charge, levied on the excess flow on a day above the booked capacity level, especially if short-term products were to be introduced

which should improve cost reflectivity and provide a fairer attribution of the revenue burden.

Some stakeholders present at the 2 March workshop expressed reservations to the suggestion that ratchets might be enhanced.

Analysis

Since the DSO currently has a licence obligation to book for the 1 in 20 peak demand level, and passes on the cost of transmission exit capacity anyway, there should be no prospect of the DSO under-booking. However, power generators may have more competitive pressures upon them

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[15] The unbooked capacity is charged as a lump sum retrospectively for the time period up to the breach and then the booked capacity is increased to this new level for the remainder of the year. This may be effected more than once during the year if there is a subsequent breach.
[16] The ratchet factor is defined here as the ratio of the capacity unit price for ratcheted units as compared to booked units.
[17] The 1 in 20 booking obligation is defined in the DSO's transportation licence

(and the potential) to book a lower level of annual capacity to optimise capacity bookings and minimise costs against wider commercial objectives. If they do so, the cost to other gas consumers inevitably increases since the total revenue to be collected is fixed.

The decision about whether some or all users should be booking to a peak design level (such as the 1 in 20 security licence criteria applying to DSOs) is an important one. The design level for a large direct offtake such as a power station for example might be based on its maximum hourly requirement, multiplied by 24.[18] The commercial discipline then would be for the hourly offtake flow not to be allowed to exceed the rated maximum, a principle which can typically be monitored and enforced for larger loads. Where capacity bookings can be made on a discretionary basis, and their use is not subject to real time enforcement, then some form of ex post commercial incentive may be appropriate, such as a ratchet mechanism and/or overrun charge.

Anticipated changes in the charge setting process[19] will allow higher forecasts for annual capacity to be used instead of the booked levels if the bookings are anticipated to be too low. Transmission capacity charges set using accurate booking forecasts reduce reconciliation payments for all users including those subject to a ratchet. In order to incentivise more accurate bookings a small increase in the ratchet factor could be considered to offset the cash flow benefit associated with under-booking.

As discussed earlier, the setting of accurate capacity charges where STC products are available becomes a more difficult process for the TSO since network users will be able to match capacity bookings closer to near-time expected flows which may be quite different from those estimated at the time of charge setting. The reconciliation process will need to deliver the necessary adjustments to capacity charges arising from the deviations of the actual bookings from those expected.

Furthermore, if STC products were to be introduced then a daily over-run charge could be more appropriate than an annual ratchet mechanism. In this case the over-run charge needs to be set at such a level that encourages the booking of capacity where usage is expected but does not penalise unexpected flows disproportionately. In the extreme if there were no over-run charge in conjunction with low STC multipliers there would be little or no incentive to book any daily capacity at all (unless there was a shortage of available capacity, which is currently not the case for the NI transmission network). Capacity procurement decisions, whether long or short-term, will be dependent on the expectation of flow and the level of multipliers applied to the STC products. Any over-run charge should take into account the level of any multipliers applied to STC products which also act as a deterrent for unexpected flows. The determination of these parameters is therefore more difficult in a regime with STC products and significant variation of the parameters is likely as network users inevitably respond to the commercial incentives. So increased volatility in charges and reconciliations can be expected as TSOs and stakeholders adapt.

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[18] This was the approach adopted in GB, consistent with assurances sought by the power stations in terms of the ongoing capability of the network to meet maximum flow rate requirements.

[19] There is currently a licence change in process to effect this. http://www.uregni.gov.uk/uploads/publications/2016-03-03_Licence_Mods_Consultation_Paper_-_FINAL.pdf . An obligation on suppliers to provide accurate forecasts was also recently introduced in the Supply Licence.

Assessment

The general considerations of equity, complexity and proportionality have to be considered in determining the operation of ratchets. There is a debate to be had regarding equitability in a regime where some but not all transmission system users have flexibility regarding booking levels. Where there is more freedom it should be expected that incentives will be needed to encourage desirable behaviours.

An initial assessment against the specific criteria identified in the Assessment Framework chapter follows. The assessment compares a regime with an enhanced ratchet application and/or overrun charge as compared to the existing basic ratchet (in the absence of any alternative incentives).

- **Cost reflectivity**

Unless specific booking levels are mandated there will be a tendency to under-book without an appropriate incentive. Where a 1 in 20 booking rule (or suitable alternative) is not mandated then booking levels may at best only match expected maximum levels for the coming year, and potentially lower. This would result in an inequitable transfer of costs from those with freedom to choose booking levels to those that do not have such flexibility. Indeed, without a ratchet that raises the capacity charge above the standard unit rate there is no incentive even to book for the annual peak level, which, by providing a beneficial cash flow for under-bookers, further exaggerates the distortion. The initial assessment against the criterion of cost reflectivity is therefore positive.

- **Efficient network use and effective development**

In practice there seems to be no direct link in NI between capacity booking levels and efficient use of the system. Similarly, effective network development in NI currently depends upon an effective planning process, rather than the level of capacity bookings.[20] The initial assessment against this criterion is therefore neutral.

- **Effective competition**

Stronger incentives would reduce uncertainty about timing of cash-flows and reduce reconciliation bullet payments. Furthermore cross-subsidy should be avoided, especially where a potential under-booking option is only available to certain customers. The initial assessment against this criterion is therefore positive.

TPA's initial assessment is that the ratchet/over-run regime could be enhanced to provide adequate booking incentives. Appropriate ratchet/over-run values need not be excessive to

[20] In other regimes, especially in USA interstate pipelines, capacity bookings would be highly relevant to effective network development, and typically a pre-condition for new investment.

provide appropriate signals and if such a change were to be chosen TPA suggests a low ratchet factor (only slightly above 1) with subsequent refinement as necessary.

However, TPA considers that the recent changes to improve the forecasts will facilitate more accurate charge setting and therefore deliver some of the benefits of an enhanced ratchet regime. Therefore TPA considers that it would be prudent to assess the effect of proposed Licence amendments before contemplating whether a modestly enhanced ratchet mechanism should be introduced.

In this case, the introduction of a suitable incentive to encourage accurate forecasting could be considered as well as, or instead of, making changes to the ratchet mechanism. The approach could involve a sliding scale incentive mechanism where the relevant network users risk and rewards are aligned with broader user interests arising from cash-flow effects of errors in the capacity forecasts used in price setting. This would mitigate any risk that an enhanced ratchet regime further adds to the problems already stated by generators; if the generator produced accurate forecasts then it would be rewarded and other users would benefit from low cash-flow adjustments via reconciliation at the year-end.

TPA therefore recommends that no changes are made to the current ratchet mechanism but that the area is kept under review in case the anticipated improvements in booking forecasts associated with proposed Licence changes are not sufficiently realised.

Stakeholders are invited to respond to the following questions:

- **Are the arguments above captured appropriately?**
- **Is the analysis appropriate? If not please explain what is missing and how such argument and analysis should be reflected in any recommendation?**
- **Are there any other critical considerations that have been missed? If so, please respond by stating the argument, providing supporting analysis and evidence, and suggesting how it should be reflected in the recommendation.**
- **Are the assessments of the case for an enhanced ratchet mechanism for the booking of exit capacity appropriate with regard to the general considerations and specific criteria? If not please explain in your response.**

Chapter 8: Commentary and Initial Recommendations

Potential reform of NI gas exit arrangements is being considered as part of the single gas transmission code initiative. This report provides a preliminary assessment of whether exit reform is necessary, and if so, what its components might be. It expresses an initial view by TPA and is designed as a call for evidence in order to elicit industry feedback.

TPA has sought to identify, and then assess, the case for reform. The co-existence of gas and electricity regimes in NI and the RoI requires joined up thinking to consider the resulting interactions and, specifically, any potential unintended consequences.

Exit reform could involve four distinct elements:

- the introduction of short-term products,
- changes to capacity booking responsibilities,
- booking platforms and
- ratchet arrangements.

Short-term products

Changes in the electricity market imply a more intermittent use of the gas transmission network by gas fired generation plant. Short-term capacity products at exit might afford an opportunity for NI generators to reduce their gas capacity costs. Any reduction in gas transmission revenue from generators would create cost redistributions that might adversely affect other gas users. We were puzzled about the benefits of short-term capacity products, given the relatively modest materiality for generators of reducing the cost of gas capacity booking compared with the scale of their other fixed and variable costs of doing business. Quantified evidence about the benefits of short-term capacity products would be welcomed in response to this consultation.

Our discussions with stakeholders now suggest that the underlying driver for the introduction of short-term products perhaps arises more from an issue about the classification of gas capacity costs in the electricity regime, rather than the actual incidence of such costs within the gas regime.

We have heard generator concern about the risk of inadequate revenues normally available under the SEM rules for NI generators to cover their fixed and variable operational costs, especially where gas exit capacity is only made available by TSOs as annual products. The generators see some potential mitigation of this concern through SEM's cost treatment of short term gas capacity products, which can serve to increase electricity prices arising compared to a regime with only annual products. They argue that the mere existence of STC products (especially relatively expensive ones) may indirectly result in higher electricity prices, and that other gas users need not be concerned about any redistribution of gas capacity costs, since generator payments for exit capacity may be maintained or even increase in future. As noted above the I-SEM conclusions document on market power mitigation, which we understand is expected in May, might provide greater clarity about how the new electricity arrangements may influence electricity wholesale market price formation including the treatment of different underlying costs and how they affect bid prices. This should provide further context for responses to this call for evidence.

We note that recent entry reform in NI has introduced short-term products to meet European legislative requirements for cross border interconnection points (IPs). Coincidentally this may have enhanced the profitability of gas-fired generation. The introduction of exit STC in NI may enhance profitability further. However, in the longer term the impact of such products will depend on how the rules for the I-SEM develop. Under the current SEM rules the existence of short term products in RoI is likely to have increased electricity prices although the potential impact has been mitigated by a 'reasonableness principle'. This principle applies equally to generators in NI. Additionally our understanding is that gas exit costs are a low proportion of the generators' fixed costs. Therefore, reform of the NI exit regime may only marginally address the concerns of power generators.

Whilst it has been suggested that exit reform is an easily delivered, no regrets option we are inclined to urge caution. Exit reform may have wider and unintended implications as explored in Chapter 4. Specifically, complexity will be increased and cost redistributions will almost certainly be created. For example, despite generator assurances to the contrary, there remain risks of increased transmission network costs falling on downstream users. And if this is not the case, then the rationale for STC reform seems to then be focussed on manufacturing increased charges to electricity consumers (in both the RoI and NI).

Reforms to ensure that both electricity and gas regimes function better, and on a more economic, efficient, and co-ordinated basis, may be desirable. Although not the focus of TPA's remit, it is clearly important that efficient electricity generators are able to recover their fixed and variable costs. The commercial framework in electricity should determine a mix of generation to ensure an adequate, and politically acceptable, security of supply. It would be inappropriate for gas regime developments to be used tactically to plug an alleged gap in the adequacy of the electricity regime in RoI and NI (currently defined by SEM), especially given the risk of adverse outcomes explored further in this paper.

We note that the I-SEM programme is currently considering the capacity remuneration mechanism and electricity trading arrangements. Our view is that this is the right arena to establish whether the generators' concerns are warranted and, given that these rules are the primary determinants of generators' revenue streams, what remedies, if any, may be appropriate. The I-SEM development might call on inputs from the associated gas regimes (from market players, TSOs, and regulators) so that the ramifications and possible refinements (if any) in the gas regime can be considered in a holistic, joined up manner.

Pending any reconsideration based upon evidence received in response to this document, our initial view is that the introduction of exit short-term products should not be undertaken at this time. This conclusion is based on the observation that the case for major and/or immediate reform of the NI gas exit regime appears weak barring a material and imminent risk of losing significant gas loads from the NI gas system.

Capacity booking responsibilities, booking platforms and ratchets

These matters primarily affect gas rather than electricity actors, unlike the cross regime effects resulting from the introduction of short-term products.

Capacity booking responsibility

We understand that there has been some suggestion that downstream network users should be required to book their own transmission exit capacity as is the case for directly connected transmission loads. Perhaps DSOs or users might prefer it if those shipping to downstream customers became responsible for individually assessing transmission exit capacity requirements, taking account of the characteristics of their own portfolio of downstream demand?

DSOs currently use a 1 in 20 security methodology for making exit capacity bookings, similar to the approach adopted in GB. As such they make an assumption of aggregate peak demand and pass on the costs of exit transmission capacity to downstream users. We understand that these aggregate capacity costs are passed on via a commodity charge.

Moving to a regime based on all downstream network users directly booking transmission exit capacity would appear to introduce unnecessary complexity in a market of the size of NI.

Pending clear evidence of concerns to the contrary, our instinct would be to recommend the continued role of DSOs to book aggregated exit capacity on behalf of downstream users.

However, if STC products were at some point in future to be introduced at exit then some consideration would need to be given to the implications for the role of DSOs booking such products, assuming that STC would not just be confined to directly connected transmission offtakes such as power generation.

We therefore conclude no further changes are appropriate at this time.

Booking platform

It has been suggested that introducing short-term products at the same time as other system developments required for the single code would be cost-effective. The PRISMA platform could be used to provide a single system for exit as well as entry capacity booking. We consider that there is a significant risk that NI may require different STCs or pricing arrangements at exit to that prescribed at entry and NI will not have sufficient control over the development costs of PRISMA should more flexibility be required. In any case this decision is considered to be subservient to the more important decision regarding the introduction of short-term products.

Our initial recommendation is not to extend the use of PRISMA to exit capacity and suggest continuing with the current exit booking processes.

Ratchet mechanism

The current network code rules do not encourage the booking of peak demand at realistic levels by those with discretion to set the level of their own choosing. The current ratchet mechanism is a weak incentive in that it simply resets the capacity booking to the maximum observed level of offtake. This may also result in unpredictable end of year reconciliation payments in a tariff regime such as that in NI.

In other regimes discipline on capacity booking may be achieved by a variety of means:

- for large (controllable) offtakes such as power stations, limiting the peak hourly flow to 1/24th of the booked daily capacity; and/or
- applying an uplift to the ratchet mechanism; and/or
- applying a (high) daily overrun charge to any flows above the booked level

We note that proposals are currently under consideration to change licences so that UR can change the forecast capacity figures submitted by the TSOs where UR considers they are not accurate. This may address some of the tariff issues whereby capacity under-forecasts will lead to reconciliation bullet refunds at year end and over-forecasts to end of year additional payments. It may therefore be prudent to consider the effectiveness of the intended change before considering whether an enhanced ratchet should be implemented.

Chapter 9: Process and next steps

This document provides preliminary conclusions about potential exit reform based upon TPA's experience and current knowledge of the NI situation.

This document is part of the process to consider whether exit reform is necessary. Stakeholders are encouraged to respond to this document to ensure that their views and quantifications can be considered prior to UR deciding on next steps including taking any decision about whether the exit regime should be reformed, and if so, how and when any reform should be implemented.

The aspiration is that wherever possible an evidenced based approach will be used to aid decision making and therefore quantified responses would be particularly welcomed. Please respond in writing to the document by no later than 27 May 2016 to Roisin McLaughlin at UR Roisin.McLaughlin@uregni.gov.uk .

Depending upon the feedback received it may be appropriate for UR and/or TPA to have further discussions with respondents.

The target is that final conclusions will be published by the end of June.